

# Performance of Generator Protection During Major System Disturbances

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Working Group J6 of the Rotating Machinery Protection Subcommittee,  
Power System Relaying Committee

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**Abstract** – Disturbance is an inherent part of any power system during the transition from one steady state operating condition to the next. Protective relays may experience abnormal operating conditions during this transient period. This paper reviews various control actions that play a part during the transition and provides technical guidance to the industry on the application and setting of generator protective relays that can operate during major system disturbances.

## I. INTRODUCTION

Every power system is subject from time to time to transient disturbances primarily due to faults and/or switching of major load. Normally the system adapts to a new steady state condition with the help of Generator Excitation and Turbine Governor Control systems. A variety of additional Power System Control schemes may also be used to help restore an acceptable new steady state condition.

One of the lessons learned from the past major disturbances is that some of the functions associated with generator protection may operate during these transient conditions. It is important for the relays to provide protection while optimizing their coordination to avoid undesirable operation during the system disturbances and thereby help preserve the integrity of the power grid.

Brief descriptions of past power system disturbances as well as generator excitation, turbine governor, and power system controls are included in this paper. The balance of the paper discusses the generator protection functions that may operate during system disturbances.

## II. POWER SYSTEM DISTURBANCES

Power system disturbances are events that produce abnormal system conditions and the state of the system may change from normal to emergency. These disturbances can be classified into two groups - small and large. Large disturbances are a challenging problem for the utilities because of the size and complexity of the power system. Adequate protection and control actions are required after a

system disturbance, to prevent further degradation of the system and restoration to the normal state.

Many system disturbances can be attributed to tight operating margins and less redundancy in generation, transmission and distribution capability. These are best addressed at the planning stage. A properly designed system is less vulnerable to large-scale disturbances. However, small disturbances cannot be eliminated due to the physical nature of the system. Overhead lines constitute a significant component of any power system and experience frequent faults that are caused by variety of reasons.

Stable operation of a power system requires a continuous matching between energy supply to the prime movers and the electrical load on the system, and an adequate reactive power support mechanism to maintain voltage within limits at different buses. These conditions are not satisfied during faults and other disturbances. During a fault, the terminal voltage dips and power transfer through the faulted system is altered depending on the type of fault. After successful clearing of the fault, the system adapts to a new steady state condition. If the fault is not cleared before the critical fault clearing time, system instability will occur.

Even the successful clearing of faults may sometimes lead to undesired relay operations because of line overloads, inadequate reactive power support and an improper relay setting. These may in turn develop into large system disturbances due to cascading. Mis-operation of relays may result in undesired and/or sympathy tripping leading to large system disturbances. Inadequate protection arrangements, such as the absence of bus-bar protection for critical system buses, may also result in system disturbances due to long fault clearing time by remote back-up protection. Loss of a large generator or a large block of load changes the system frequency and may alter the reactive power flow in the network. This requires control action, like underfrequency load shedding, to restore the system frequency and voltage at different buses within limits.

Performance of the generator excitation system and the turbine control system are important during a system disturbance. Coordination between these systems, system

protection and other control strategies are necessary to avoid system collapse. Transient and Dynamic stability studies should be periodically conducted in order to develop adequate control and protection strategies.

### **Excitation Control**

The excitation system of a generator provides the energy for the magnetic field that keeps the generator in synchronism with the power system. In addition to maintaining the synchronism of the generator, the excitation system also affects the amount of reactive power that the generator may absorb or produce. If the terminal voltage is fixed, increasing the excitation power will increase the synchronizing torque of the machine, and increase the reactive power output. Decreasing the excitation power will have the opposite effect, and in extreme cases, may result in loss of synchronism of the generator with the power system. If the generator is operating isolated from a power system, and there are no other reactive power sources controlling terminal voltage, increasing the level of excitation power will increase the generator terminal voltage and vice versa.

There are a variety of control functions that can be applied to the excitation system, including automatic voltage regulation (AVR), constant power factor regulation, and constant reactive power regulation. The excitation system may also operate in manual control with no automatic regulation. All of the automatic control modes may have supplementary controls. These supplementary controls may ensure that even under automatic regulation of a primary parameter, the generator is always operated within its capability limits. Supplementary controls may also enhance the stable operation of the generator in parallel with a power system. Supplementary controls may include the following:

- Maximum and/or minimum excitation level limits (OEL / MEL respectively, these limits may be time dependent)
- Stator current limit to prevent stator thermal overload
- Volts per hertz limit to prevent equipment damage due to excessive flux levels
- Terminal voltage limit to prevent equipment damage due to excessive dielectric stress
- Line drop compensation to increase generator response to system voltage depressions
- Reactive power sharing controls for generators trying to regulate the same parameter
- Power system stabilizer to damp low frequency oscillations.
- Under Excited Limit (UEL) to protect against generator stator end-winding heating while operating in the underexcited mode. [15]

The most commonly used control mode for generators of significant size that are connected to a power system is the AVR mode. In this mode the excitation system helps to maintain power system voltage within acceptable limits by

supplying or absorbing reactive power as required, and also helps maintain synchronism of the generator with the power system by increasing synchronizing torque when required.

In stable steady state operation, a power system has an exact match of mechanical power delivered to generators and electrical power consumed by loads. Further, the voltage is regulated within narrow limits. Small disturbances resulting in power or voltage oscillations are quickly damped. Frequency is maintained within acceptable limits by turbine governor controls and sometimes by system load control as noted in other sections of this paper. During large disturbances, excitation controls act to maintain system stability. For major disturbances, the terminal voltage change is sufficient that the output of the excitation is either full on – at ceiling, or full off. The AVR is the main control function in most cases, but the supplementary controls provide important features.

Large system disturbances are typically caused by short-circuits of different types. The opening of appropriate high-speed breakers isolates the fault. During the fault, the terminal voltage dips and in response, the exciter increases its output voltage to ceiling which causes the excitation current into the field to increase at a rate determined by the voltage divided by the inductance of the field.

System disturbances are also caused when a generation unit is suddenly dropped, or when a breaker is suddenly opened and a load is dropped. When a unit is dropped, other nearby units pick up the load of the dropped unit and in response to the drop in terminal voltage the excitation of each of these units will increase. When a breaker is suddenly opened and a load is dropped the excitation will be reduced.

The electrical power,  $P_e$ , transferred from the generator, an electric machine, to the load is given by the equation:

$$P_e = \frac{EE_l}{X_t} \sin \delta \quad (1)$$

$E$  = Internal Voltage and is proportional to the excitation current.

$E_l$  = Load Voltage.

$X_t$  = Reactance between the generator and the load.

$\delta$  = Delta, the angle that the Internal Voltage leads the Load Voltage.

$$P_a = P_m - P_e \quad (2)$$

$P_m$  = Mechanical Turbine Power of the generating unit

$P_e$  = Electromagnetic Power output of the generating unit

$P_a$  = Accelerating Power

The mechanical power,  $P_m$ , is provided by the turbine and the average mechanical power must be equal to the average electrical power. When a system disturbance occurs there is

a change in one of the parameters of the electrical power equation. For faults, typically the reactance between the generator and the load ( $X_l$ ), the load voltage ( $E_l$ ), or some combination of these two parameters causes the electrical power to change. For example, for a short circuit the load voltage is reduced, for a breaker opening the reactance increases. When a generation unit trips offline, the required electrical power from the remaining generators increases.

In both cases the instantaneous mechanical power provided by the turbine is no longer equal to the instantaneous electrical power delivered or required by the load. This difference must be accounted for.

For a short time after a disturbance the turbine control will not have much affect on the turbine power and the rotor will either absorb or provide the required transient energy. In the case of a fault, the energy absorbed by the rotor increases its angular velocity. When the load on a unit is suddenly increased, the energy furnished by the rotor results in a decrease in the rotor angular velocity. The exciter will respond to these disturbances based on terminal voltage measured.

To understand what is happening let us consider the example of a three phase solid fault at the load. The load voltage is shorted ( $E_l = 0$ ), and the reactance between the generator and the load ( $X_l$ ) is unchanged. From Equation 1, the electrical power during the fault is zero. Since the turbine control cannot instantaneously reduce its power output, the power that was previously input to the load now accelerates the combined rotating mass of both the generator and turbine rotors (see Equation 2). This causes angle delta to increase. The excitation, in response to the reduced terminal voltage increases its voltage output to ceiling causing the internal voltage ( $E$ ) of the generator to increase at a rate determined by the operating time constant of the field and the ceiling voltage. Assuming that a generator trip has not occurred, when the fault clears and the load voltage is restored, the new internal voltage and the new delta now determine the electrical power delivered to the load, still defined by equation 1. This “new electrical power” must be larger than the mechanical power input by the turbine in order that the kinetic energy gained by the rotor during the fault is removed. If the “new electrical power” is less than the mechanical power, the rotor will continue to accelerate and the generator will lose synchronism. Exciters with high ceiling voltages and fast response times help the Internal Voltage of the machine to get big rapidly, increasing the “new electric power”, and thus increase the probability that the kinetic energy gained during the fault will be removed from the rotor. If this energy is not removed the generator will lose synchronism and a subsequent trip will result.

In disturbances where short circuits depress the system voltage, pre-fault electrical power cannot fully be delivered through the transmission system. Transient stability becomes a threat to the power system within a time frame of less than one second. During the short circuit, the generator rotor accelerates due to mismatch of the reduced electrical power output with the constant mechanical power input (in the transient time frame before the turbine governor control can react). Fast response of the AVR and excitation system is important to increase the synchronizing torque to allow the generator to remain in synchronism with the system. After the short circuit has been cleared, the resulting oscillations of the generator rotor speed with respect to the system frequency, will cause the terminal voltage to fluctuate above and below the AVR set point. Supplementary excitation controls may be called upon to prevent the AVR from imposing unacceptable conditions upon the generator. The supplementary controls in this case are usually maximum and minimum excitation limiters. The overexcitation limiter (OEL) prevents the AVR from trying to supply more excitation current than the excitation system can supply or the generator field can withstand. The OEL must limit excitation current before the exciter system short circuit or overload protection operates, and before the generator field overload protection operates. The minimum excitation limiter (MEL) prevents the AVR from reducing excitation to such a low level that the generator is in danger of losing synchronism. The MEL must prevent reduction of current to a level where the generator loss of field protection may operate. UEL protects against generator stator end winding heating during underexcited operation.

In extended disturbances beyond the transient stability time frame, the AVR again tries to regulate voltage, but in this case it will attempt to steadily increase or reduce excitation to regulate voltage. Periodic oscillations are not evident as in the case of challenges to transient stability and the system stress may persist for periods of up to tens of seconds or even longer. Prolonged low voltages may result from loss of important transmission capability or loss of important sources of reactive power support. These transmission and generation low voltages may be exacerbated over a long time frame as system controls such as distribution voltage regulators attempt to maintain distribution voltage levels. Prolonged high voltages may result in the case of sudden loss of load together with inability of available connected reactive power sinks to absorb reactive power generated by unregulated sources such as capacitor banks. Again the supplementary controls of OEL and MEL may operate, and additional controls such as the volts per hertz or terminal voltage or stator current limiters may also operate. The voltage deviations from normal levels may persist for extended durations, so coordination of the supplementary controls with other protection systems over a long time frame, and possibly even in steady state, is important.

Supplementary excitation controls such as line drop compensation and reactive power sharing are sometimes applied to maintain system voltage within tolerable limits. These controls must coordinate with system controls (such as reactive power equipment switching) that also regulate system voltage. Power system stabilizers (PSS) are normally required to damp small system oscillations. PSS must be in service, and properly tuned, but are not normally coordinated with any generator protection systems.

It is evident from the above review of excitation control systems that the AVR is a vital control system that should be in service at all times. In North America, regional reliability criteria require that system transmission operators have positive assurance that generator excitation controls are in service and that specified generator real and reactive power capability is available. Assurance of generator capability may require periodic testing of the controls to ensure their steady state and dynamic coordination with protection systems. Assurance of control system status may require supplementary SCADA control points to provide real time information to operators.

### **Turbine Governor Control**

The major role of the turbine governor control is to maintain proper speed regulation and load division for the generating units on the power system. Two types of control are used, “Droop” and “Frequency or Isochronous (constant speed)” depending on the units operation and control requirements.

Droop (speed/load) control behaves with a characteristic that as load increases speed drops. With synchronous machines their operation is locked at system frequency. Therefore the droop governor becomes a load controller. As load increases, the governor signals the governor valves to open to maintain the established speed setting and accommodate the additional system load. Governor droop control prevents one generator from trying to pick up the entire additional load. Important benefits are the load change being shared among units and better overall system stability.

Isochronous (frequency) governor control is used to operate the unit isolated from the power system. This control regulates the system frequency to the reference. This would be analogous to a human operator adjusting the turbine to a specific speed (frequency) reference. During an islanded condition this type of control is important to establish the system frequency at or near rated conditions.

When required, only one unit is set in isochronous to provide the frequency reference for a system. If other units are connected they are in droop control. This is done to avoid conflict, excessive loading and unloading between units.

Although two modes of control are available, “droop” and “isochronous”, the droop mode is almost universally used for generators interconnected in a large power system. In the

isochronous mode, the governor attempts to regulate the generator to a fixed frequency setting. Since a single generator has almost negligible effect on the frequency of a large power system, isochronous control is not normally an effective mode.

During system disturbances a sudden mismatch between generation and load may result from a loss of load, transmission capability, or generation, or any combination of those features. If the mismatch between generation and load is significant, system control actions will normally act first to quickly restore a rough balance between load and generation. These system control actions are usually automatic underfrequency load shedding, automatic generator shedding, or automatic application of braking loads. Automatic load restoration may also be applied after some time delays to reduce system frequency after disturbances involving islanding. After the system control actions have roughly restored generation/load balance, the speed control feature of all the interconnected generators act together to adjust combined generator power outputs to restore system frequency to normal levels. Ideally all droop settings on turbine governors (except base load units) in an interconnected system should be the same to coordinate unit response to a frequency change. If all droop settings were the same, the generators would share loads in proportion to their rating during coordinated frequency adjustment after disturbances.

Many generators are not capable of operation for more than a very short time outside narrow frequency deviations above or below rated frequency. Turbine governor controls will include supplementary limiters to prevent the generator from operating in an islanded mode outside those frequency limits. These generators usually also have abnormal frequency protective equipment to disconnect them from the power system before the turbine can be damaged by operation outside prescribed limits. The turbine governor limiters must be coordinated with the abnormal frequency protection of the generators so that the limiters prevent the generator from operating in a region where the protection may trip it. Of course in an interconnected power system where the frequency is not determined by the turbine governor, automatic system controls must be relied upon to prevent the generator from operating at a frequency where it may be tripped off line by the automatic abnormal frequency protection. If the generators are removed from the system before the automatic system controls can act, the disturbance will be exacerbated, and the system controls may be ineffective.

The system or regional dispatcher uses a common system controller or area controller to maintain system frequency and energy interchange schedules. This common control unit (automatic generator control system, or AGC) supervises each unit’s turbine governor control, system

frequency and interchange schedules and dispatches corrections to the unit's turbine governor controllers accordingly.

During some system disturbances where interconnected regions may become separated, scheduled interchanges can no longer be maintained during the immediate post disturbance time frame. If AGC is still in service, it may adjust turbine governors in a fruitless attempt to maintain scheduled interchanges through transmission paths that no longer exist. Such blind AGC action may result in unacceptable load flows or system frequency deviations. Special protection systems applied for system protection purposes may include control actions to suspend AGC until interchange schedules can be readjusted, and/or transmission paths restored to service. When AGC is suspended the turbine governor speed references remain fixed and system frequency is brought back to near normal by system control actions acting together with turbine governor control actions using the fixed speed references.

It can be seen therefore, that because of limited individual effect on system frequency, turbine governor controls have less interaction with system and/or generator protection systems than generator excitation controls. However, proper setting of the governor controls is critical for maintenance of acceptable system frequency and reasonable unit load division after disturbances. Further, turbine governor controls may become an integral part of special protection systems to maintain acceptable system performance in the post disturbance period.

### **System Control**

System control actions are usually expected to mitigate the effect of disturbances before any equipment (including generators) becomes in danger of being physically damaged. These system controls are often called special protection schemes or remedial action schemes. It is expected that generator protective devices will coordinate with the generator capability to withstand abnormal operating conditions. However, it is important that such protective devices also coordinate with the power system special protection schemes, which are intended to limit the abnormal operating conditions to within the generator capabilities. Some common special protection schemes are noted below.

Underfrequency load shedding is applied to prevent extended system operation at low frequency. The possibility of such operation arises when there is a sudden and significant loss of generation or addition of load. Underfrequency load shedding is usually expected to operate when there is such a large mismatch between load and generation that normal governor action cannot be expected to restore nominal frequency to prevent equipment damage from sustained low frequency operation. Underfrequency load shedding is usually applied to shed increasing blocks of

load at discrete frequency levels. It is important that the frequency levels and time delays (if any) be coordinated with any turbine/generator underfrequency protection that is applied on the system so that all the load that is available to be shed, is shed before any generator is tripped to protect it from damage.

Voltage stability load shedding may be applied to prevent extended system operation at low voltages. The possibility of such operation arises when there is a lack of reactive power required to maintain system voltage levels within acceptable limits. This voltage stability load shedding is often initiated by sustained low voltages with or without the presence of other indicators of insufficient reactive power availability. It is important that the voltage stability load shedding be coordinated with any generator protection that may operate during low voltages or high reactive power output levels. Some types of generator protection that could operate during high reactive power output are field overload protection, exciter protection, exciter transformer protection, and field ground fault protection. Some types of generator protection that could operate during low voltages (and associated high currents) are voltage restrained or controlled overcurrent protection, under impedance protection, and stator overload protection.

Other system control actions, which respond to low voltages, include the following: Reactor and capacitor switching to increase the amount of reactive power supplied to the system, HVDC fast ramping, tie line switching, and generator governor action to reduce the real power flow in the transmission system and thereby reduce reactive power demand. Again, generator protection, which responds to low voltages and high currents, should coordinate with such control actions.

Some special protection schemes separate out of step systems at suitable tie points. Generator protection, which responds to out of step conditions, should also coordinate with such schemes. Generator out of step protection, under impedance protection and voltage controlled or restrained overcurrent protection may undesirably respond to out of step conditions before system special protection schemes can act to remove the out of step condition.

Some other special protection schemes operate to prevent thermal overload from damaging equipment. Such schemes usually shed load, separate system tie lines, or start local generation or take emergency control of HVDC. It is important that generator protection, which might respond to unusually heavy load, should coordinate with any thermal overload system special protection schemes. Some generator protection that may respond to heavy load includes stator overcurrent protection, stator overload protection, and field overload protection

### III. HISTORICAL PERSPECTIVE

#### August 10, 1996 WSCC Disturbance [14]

On August 10, 1996, a major disturbance separated the Western Systems Coordinating Council (WSCC) system in to four islands, interrupting service to 7.5 million customers for periods ranging from several minutes to about 9 hours. The results of the survey after this disturbance and the lessons learned are summarized below:

<u>Cause</u>	<u>Units Tripped</u>	<u>Total MW</u>
Power plant Problems	22	7,167
Transmission loss/Load rejection	25	3,826
Unknown	11	2,722
System swing	10	2,423
Low frequency	31	2,018
High voltage	5	1,733
Low voltage	18	1,390
Excitation control/Field problems	6	1,075
Operator reaction	2	362
Relay action	<u>5</u>	<u>272</u>
	135	22,988

1. Sustained low voltage: 16.3 percent of tripped units were due to problems within the power plant such as low drum level, low pressure, etc. Many of these problems were a direct result of the sustained low voltage. The low voltage caused many auxiliary support systems to either trip or transfer to backups. In some cases, the transfer was unsuccessful. Some utilities were adding Uninterruptible Power Supply (UPS) systems to critical plant control circuits to prevent such an incident in the future. Under-voltage relays on auxiliary support system tripped due to the fluctuated voltage power supplies during this disturbance.

2. Load rejection: The survey indicated that 18.5 percent of the units affected tripped due to load rejection. The utilities had to verify that the transmission loss was appropriate for the circumstances.

For the hydro units during load rejection, the voltages were boosted to the ceiling. The duration of the over-voltage above relay settings were depending on the type of the exciter equipment and their control. Also, the speed (frequency) of some hydro units during load rejection became 200% of the normal speed (120-hertz), and the response time (bring down to safety level) is varied depending on the governor response time and the water head ( $WK^2$  kinetic energy). For non-fault load rejection, units should not be locked out, however, some relays (third-harmonic neutral under-voltage relay, fundamental neutral over-voltage relay, over-voltage relay, over-frequency relay) initiated to trip and lockout units. Some of them were due to coordination problems, but others were due to protective relays' performance (depends upon

the filter design- Fourier type, RMS type, or other filters) during higher frequency operation.

3. Backup overcurrent relays: Several units were tripped when the voltage restrained overcurrent relays or directional overcurrent relays tripped during a swing or sustained low voltage. Two large units are known to have tripped during such system disturbance. This type of problem should be considered during setting calculations of the overcurrent relays.

4. Under-frequency relays: Several units tripped by under-frequency relay. Under-frequency tripping schemes need to coordinate with the manufacturers' recommendations on low frequency turbine operation. Hydro plants do not require under-frequency tripping for turbine protection. However, some utilities had application of the under-frequency relays on their generators. These relays lacked under-voltage supervision and some of them operated during this disturbance.

5. Exciter/Field problems: Several units tripped due to exciter control or field problems - loss of field, field failure relay or excessive field current. Volts-per-hertz detection initiated many of these trips. The mis-coordination of Volts/hertz protection and generator over-voltage protection with respect to the over-excitation limiters as well as the mis-coordination of loss-of-field relays over under-excitation limiters caused the nuisance trips.

6. Unknown causes: There were a large number of plants (11 totaling 2,722 MW), which tripped for unknown reasons. Currently, a large number of power plants do not have sequence of events and oscillography recorders other than the limited annunciator (alarm windows) displays. Therefore, a large number of power plant trips were reported as "Unknown Cause."

7. High voltage: High voltage in some portions of the system also created problems for plants. Many of the loss of field relay trips were due to the high voltage.

8. Operator intervened: Two plants tripped as operators manually intervened.

#### February 21, 1995 PECO disturbance

On February 21, 1995 at 3:05 a.m., a 230-kV lightning arrester on the 220-16 line from Whipain Substation to North Wales Substation failed. The ensuing fault was cleared in 5 cycles by actions of the relays and breakers at the line terminals. However, in addition to the faulted line, 6 other transmission lines incorrectly tripped for various reasons. Approximately 1 second later, at North Wales, the line automatically reclosed into the fault. The North Wales relays failed to clear the fault, which lasted for 114 cycles before being cleared by the action of relays and breakers at remote stations. During the second fault, 4 more

transmission lines tripped for various causes. In addition, during the second fault, the Limerick 1 and 2 generators were tripped by ground overcurrent relays connected to their step-up transformers.

#### **August 22, 1987 Tennessee Disturbance**

On August 22, 1987, during a heat storm, a 115 KV switch that belonged to Memphis Light, Gas & Water Division flashed phase-to-phase while their operator was attempting to isolate a damaged air blast breaker. Because the faulted bus lacked a bus differential protection scheme, the fault continued for more than a second and was eventually cleared by backup relays at remote locations. Due to the long fault duration, motor loads in Memphis and the surrounding TVA area began to stall and draw large amounts of reactive power even after the fault was cleared. A depressed voltage condition developed on both the 161- and 50-KV systems in Southwestern Tennessee and continued for 10 to 15 seconds. During this time, zone 3 distance relays at several remote substations began to trip. Voltage controlled/restrained overcurrent and distance relays on generators also tripped. This started a cascading effect that eventually tripped all source lines into TVA's South Jackson, Milan, and Covington substations. [12]

#### **June 5, 1967 PJM Disturbance**

At approximately 10:23AM on June 5, 1967 the eastern portion of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection experienced a complete loss of power. Prior to this event, the area was experiencing heavy loads and power transfers. The disturbance was initiated at 10:16AM when a 230kV line between Nottingham and Plymouth Meeting in the Philadelphia area sagged due to heavy loading and flashed over when it contacted a 4kV circuit. Over the next few minutes, line loadings increased and voltages sagged at various locations in the PJM area. Reactive loadings on generators increased to support system voltage. System conditions were aggravated by the tripping of Unit #2 at the Brunner Island plant near Harrisburg, Pa. This unit was loaded to 392 MW and tripped by action of loss-of-field relaying about 30 seconds after the initial event. Isolation of eastern PJM occurred about 2 minutes into the event. Collapse of the island occurred about 5 minutes later. About 26 generators were automatically tripped during this disturbance—12 by loss-of-field relaying, 6 due to abnormal current or voltage, 4 by turbine protection, and 4 by other protective devices. Prior to the initial disturbance, the load in the affected area was 9,279 MW.

#### **IV. GENERATOR PROTECTION PERFORMANCE**

There are several lessons to be learned from the past system disturbances. Improvements in transmission line right-of-way maintenance programs and communications among the system operators along with more extensive system studies can minimize the disturbances. Also better understanding of

the protective relay performance during the disturbance conditions can avoid false operation and help restore the system. The generator protection elements requiring special considerations are outlined below.

#### **System Backup Protection**

Backup protection for generators is usually divided into three areas: Phase backup protection (51V-R voltage restrained or 51V-C voltage controlled overcurrent or 21 distance), unbalance protection (46 negative sequence overcurrent), and ground backup (51N high side neutral overcurrent) relaying. All of these functions are time-delayed such that the primary protection has a chance to operate before the backup protection. Negative sequence overcurrent relays are typically set at the generator capability and provide secure protection during system faults and disturbances.

Phase and ground backup relays were involved in several of the system disturbances reported earlier in this paper. Two generators were tripped by ground overcurrent relays connected to their step-up transformers when a transmission line closed into a fault and failed to clear for 114 cycles. Depressed voltage lasting 10 to 15 seconds tripped distance zone three relays at several remote substations along with 51V and 21 relays on generators. Six units during the PJM blackout were tripped due to abnormal current or voltage.

The nature of backup protection produces a large proportion of incorrect relay operations relative to the number of correct ones [4]. This is because the primary protection usually operates first and correctly. The opportunities for correct back-up operations are very limited compared to the number of exposures to the possibility of an incorrect operation. It can also become an issue of semantics to determine a correct or incorrect operation. Operation of a multi-phase fault backup relay during a swing situation can be considered a correct operation even though it may be unwanted.

#### *Phase Backup*

System phase backup protection of generators is traditionally done by one of two types of relays. For smaller units, the voltage-controlled overcurrent 51V-C or voltage-restrained overcurrent relay 51V-R is used. For larger units, with distance relays on the lines out of the plant, a distance type 21 relay is usually used. These relays are usually connected to the generator VTs and the generator neutral side CTs.

Correct functioning of 51V relays depends on the voltage drop at the generator terminals during the fault. For generators connected to a weak system, the generator terminal voltage for system faults may not be different enough from the normal voltage to provide adequate margin for correct relay operation.

For voltage controlled 51V-C type relays, the overcurrent pickup is typically set below generator nameplate current. The control voltage setting should be below the lowest

credible voltage the power system may operate at. Choosing too high a voltage may allow an undesired operation of the relay during wide-area disturbances. For the voltage restrained 51V-R type relays, the pickup setting is usually above the generator nameplate current. As the voltage decreases, the relay lowers the overcurrent pickup proportionately to levels below load. In this sense, this relay is measuring generator capability times a multiplying factor while at normal voltage and at lower voltages becomes more like the voltage controlled 51V-C. These relays are not directional and operate independent of the angle between voltage and current. Therefore, they will operate at all power factors. Typical relay time delays are about half a second or more to coordinate with transmission line back-up overcurrent relays.

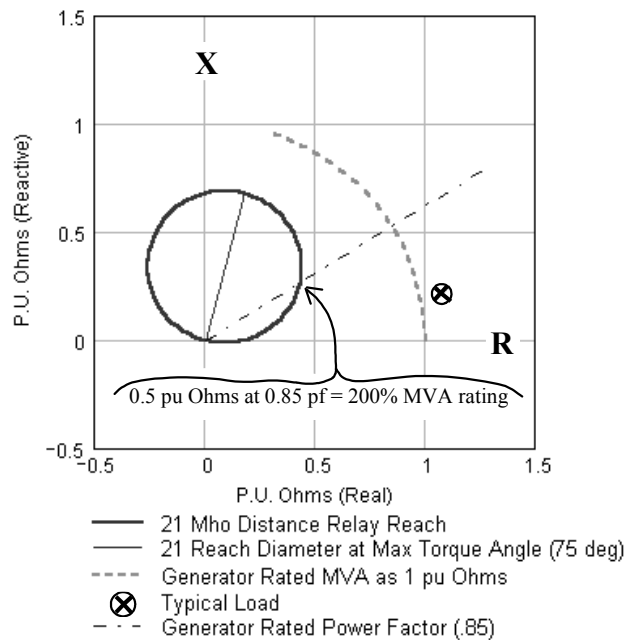
Distance relays are traditionally set to look away from the generator toward the power system. Often they are applied with no offset so that the location of the generator VTs lies on the mho characteristic circle. In theory the reach is set to cover the longest line out of the station including the effects of infeed. This is not always an achievable setting. The reach setting must remain conservatively above the machine rating to prevent inadvertent trips on generator swings and severe voltage disturbances. These criteria normally require compromises in the desired protection to maintain generator security. A long reach setting should be checked for coordination with auxiliary bus time overcurrent relays and must allow for the generator response to short time system overloads or recoverable generator swings. Because of these conditions, distance relays should be set to carry more than 200% of the MVA rating of the generator [4] [9] at its rated power factor.

In the traditional reach calculation, the mho circle maximum reach or angle of maximum torque is determined from the impedance of the step-up transformer and the longest transmission line out of the station. Protecting transmission lines at the angle of maximum torque can produce settings more sensitive than 200% of the generator rating. Normally the load would not be near this angle of maximum torque but more near the real axis as shown in Figure 1. The relay's reach can be calculated to allow at least 200% of the machine MVA rating at the machine's rated power factor.

With the use of ground backup and a negative sequence relay, coupled with increased use of local back-up policies on the transmission system, the need for long forward-looking phase distance backup operation is minimized. Voltage regulator boosting in response to a system overload can produce the critical steady state condition for limiting the relay reach; however, overriding a recoverable swing will probably be the more critical constraint [4].

The distance relay time delays are set to coordinate with the distance protection of the lines leaving the power station. This represents a delayed trip that can allow transmission

line zone 2 and breaker failure to operate first. If the lines out of the power plant are protected by a pilot system, the delay may be calculated to coordinate with just the breaker failure time [4].



**Figure 1—Setting 21 Distance Relay for 200% Rated MVA at Rated PF**

#### Ground Backup

Ground backup protection for the transmission lines leaving the generating station is typically provided by a time-overcurrent relay in the high-side neutral of the generator step-up transformer. Particular attention should be paid to coordination with ground distance protection on the transmission lines. Any high-resistance ground fault outside the reach of the ground distance relay should not be seen by the backup ground relay. The backup ground protection should pick up for a ground fault at the end of all lines out of the station. Overcurrent coordination requires pick up to be higher than the highest ground relay setting of the lines leaving the station. For coordination with line ground distance relays, the backup relay should be set above the highest system ground fault within the distance relay's fault resistance limit [4].

#### Loss of Excitation Protection

Loss of Excitation (LOF) in a synchronous generator results in the generator continuing to operate as an induction generator causing induced heating in the field and associated parts, reactive current overload of stator winding, and possible voltage stability problems on the system. A

traditional impedance relay or reverse var relay can detect the large reactive flow into the generator.

Some of the abnormal operating conditions that can affect the impedance type of LOF protection are:

- Power swing disturbances,
- Lowered frequency,
- High level of leading reactive load

*Power Swing Disturbances*

If not carefully set, the LOF relay can trip on a stable transient swing that encroaches on the relay characteristic. A study into the effect of power swings was conducted with the result of the worst case stable swing occurring when the voltage regulator was out of service, the system impedance was low, fault clearing time was at a critical switching time (for a three phase fault on the high side of the GSU), and the generator at leading power factor. For a critical clearing time of 0.18 seconds and the machine initially operating with 0.95 leading power factor, the locus of the swing stayed within the LOF characteristic (diameter =  $X_{syn}$ ) for 0.3 seconds. A fast response voltage regulator tends to drive the impedance locus away from the relay characteristics. [7]

The LOF relay under some system conditions may be set to detect a generator loss of synchronism. With voltage regulator in service and the relay set to not operate for a stable swing, the LOF relay may not detect a loss of synchronism.

*Low Frequency Disturbances*

Some system disturbances result in islands of generation/load with excess generation in some areas and a shortage in others. When load exceeds generation capability, under-frequency results.

In major disturbances in the PJM service area and Northeast, LOF protection tripped a number of generators. A study revealed that the trips were a result of a combination of the generators being on manual control (either initially or switched after the voltage regulators exceeded ceiling limit timeout) and having excitation outputs which were frequency dependent (e.g. shaft driven exciters). As the frequency decreases the field voltage (on manual control) decreases to the point where the machine will either pull out of step or the field will totally collapse. Impedance type LOF relay characteristics shrink with reduced frequency and rotate into the third quadrant on the R-X diagram. In some cases the relays detected a loss of excitation and in other cases a loss of synchronism – both of which were considered desirable relay operations. [7][6]

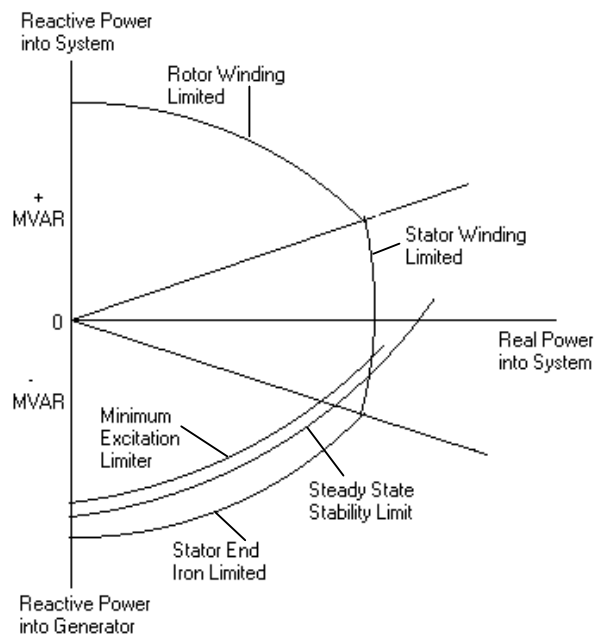
Modern relays are available which are insensitive to frequency variations, which monitor excitation voltage for accelerated tripping, and which can be directly set to coordinate with machine under-excitation limiters.

*High leading reactive load*

In one instance at Idaho Power, the combination of light load and line charging current drove the machine into such a leading power factor that it encroached on the LOF characteristic resulting in a trip. [6]

Two techniques for detecting LOF via impedance measurement are described in the IEEE Guide for AC Generator Protection. Time delay settings proposed for LOF protection account for stable swings. [10]

Care should be taken to co-ordinate LOF protection and the excitation system Minimum Excitation Limit (MEL) settings. A typical WATT-VAR capability curve for a generator is shown in Figure 2 with typical steady state stability limits indicated. Also, if possible, a dynamic stability study should be run to establish suitable delay settings on stable power swings.



**Figure 2: Capability Curve of a generator**

**Overexcitation Protection**

Generators, as well as their associated power plant transformers (GSU's and auxiliary transformers) have a limited capability to operate for sustained periods at high voltages and low frequencies. These conditions can be imposed upon generators and power plant transformers as a result of major power system disturbances. This is especially true if these disturbances involve the creation of power system islands. If these extreme voltage/frequency conditions are not corrected, they can result in overexcitation. Overexcitation of generators and transformers will result in thermal damage to cores due to excessively high flux. Core flux is directly proportional to voltage and inversely

proportional to frequency. Excess flux saturates the core steel and flows into the adjacent support structure causing high eddy current losses in the core and adjacent conducting materials. Severe overexcitation can cause rapid damage and equipment failure. It is general practice to provide V/Hz relaying at power plants to protect generators and transformers from these excessive magnetic flux density levels. This protection is typically independent of the generator voltage control in the generator excitation system.

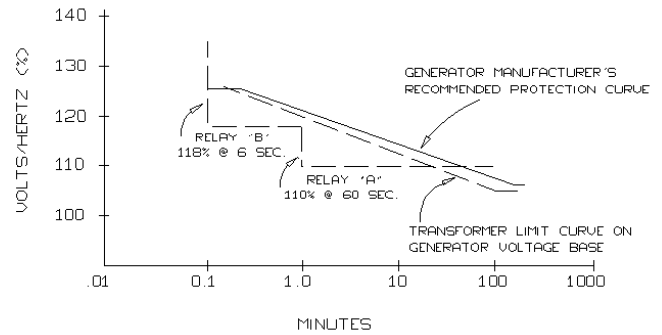
Overexcitation of a generator or any transformers connected to the generator terminals will typically occur whenever the ratio of the voltage to frequency, expressed as volts per hertz (V/Hz), applied to the terminals of the equipment exceeds design limits. These design limits are specified in ANSI/IEEE C50.13 (generators) and C57.12 (transformers). Continuous operating capabilities are indicated below:

- Generators 1.05 p.u. (generator base)
- Transformers 1.05 p.u. (on transformer secondary base) at rated load 0.8 pf or greater; 1.1 p.u. (transformer base) at no load.

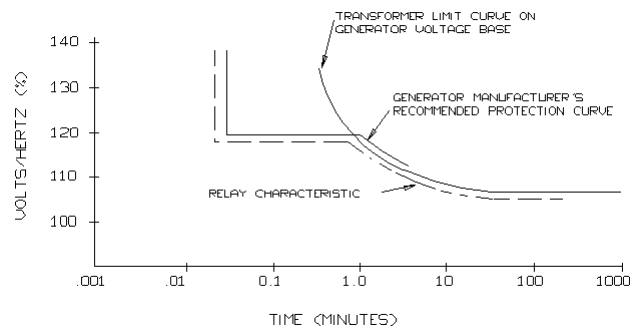
*Overexcitation due to Overvoltage*

When a power system island is formed during a major system disturbance, it may have excessive VARS in relationship to VAR load. These VAR sources are shunt capacitors, as well as VARS produced by generators within the island. Sudden power system disturbances can also unload transmission lines whose shunt capacitance can contribute to high VAR levels within the island. Ideally, control actions, such as tripping of shunt capacitor banks within the island will reduce system voltage to within generator and transformer continuous capabilities. At power plants, automatic generator excitation control will reduce VAR output to control voltage within the island. If required, generators can operate underexcited and absorb VARS. The amount of VARS that the generator can absorb is limited by the generator underexcited capability, which is limited by stator end iron heating. Other considerations, such as steady-state stability limits and Loss of Excitation Protection can also limit underexcited generator operation. The minimum excitation limiter in the voltage regulator limits the VAR intake level. This is a settable control within the generator voltage regulator that needs to be properly adjusted, as illustrated in Figure 2, to coordinate with generator capability and steady state stability limitations. If during a major system disturbance, the generator excitation control is in manual, none of the generator control actions described above will take place and the generator VAR output will not be reduced to lower system voltage. If a significant number of generators within an island formed during a major disturbance are operating with their voltage regulator control in manual, it will greatly exacerbate high voltage problems with the island.

If high voltage during a major system disturbance is not reduced to within generator and transformer capabilities, protection is provided to trip generators and their associated transformers. At power plants, V/Hz protection is usually supplied from VT's at the terminals of the generator. This protection is typically set to protect the generator, GSU and auxiliary transformers. Figures 3A and 3B show typical V/Hz vs. time capability curves for generator and transformer. These curves should be plotted on a common voltage base and the V/Hz protection coordinated with the short time capability as illustrated.



**Figure 3A Typical Relay Characteristics for Dual Level, Definite-Time V/Hz Protection**



**Figure 3B Typical Relay Characteristics for Combined Inverse-Time and Definite-Time V/Hz Protection**

*Overexcitation Due to Underfrequency*

A V/Hz overexcitation condition can also occur due to low system frequency resulting from a major system disturbance. This, however, is a less likely cause than high voltage. At normal voltage (1.0 p.u.), the frequency would have to drop to 95% of normal (57HZ) to exceed the 1.05 p.u. continuous capabilities of generators and transformers. System underfrequency load shedding, as well as generator underfrequency protection discussed next in this paper, makes sustained operation at very low frequencies unlikely. V/Hz relays will provide protection for this event if it occurs. Its trip time is usually much slower than underfrequency relaying.

### **Abnormal Frequency Protection**

When a power system is in stable operation at normal frequency, the total mechanical power input from the prime movers to the generator is equal to the sum of all the connected loads. Any significant upset of this balance causes a change in frequency.

Turbine capabilities at abnormal frequency are generally more restrictive than generators and transformers. Operation of generators at low frequencies can result in overheating, due to reduced ventilation.

Specifically, turbine blade fatigue on steam turbines (and possibly combustion turbines over 200 MW) is the main concern. Blade fatigue is cumulative and non-reversible. The fatigue stress on the blades depends on their resonant frequencies, which are dictated by blade design and length. Steam turbines are composed of multiple stages of various steam pressures; each stage composed of blades of different lengths. Combustion turbines (particularly under 200 MW) have limited number of blade sizes and therefore have fewer resonant frequencies.

#### *Turbine Over/Underfrequency Operational Limits*

Operation of a turbine between 59.5 and 60.5 Hz (in a 60 Hz system) is considered within the unrestricted time operating frequency limits, whereas the operation above 60.5 Hz and below 59.5 Hz are regions of restricted time operating frequency limits. Continuous operation in this region under generator-loaded condition is not recommended.

Time spent in a given frequency band is cumulative, and is usually considered to be independent of the time accumulated in any other band. For each incident, the first ten cycles in a given frequency band are not accumulated since some time is required for mechanical resonance to be established in the turbine blades. It should be recognized that the fatigue life is used up during abnormal underfrequency operation. It should be noted that when a series of underfrequency events occur, the sequence of the events influences the total fatigue life, as the first underfrequency event will weaken the turbine blades and reduce the number of cycles to failure for subsequent events. [13]

#### *Protective System Philosophy*

Turbine overfrequency relay protection is generally not required because governor runback controls or operator action are counted upon to correct the turbine speed. Overfrequency is usually the result of a sudden reduction in load or unit full load rejection and, therefore, corresponds to light-load or no-load operation of a generator. During overfrequency operation, machine ventilation is improved and the flux density required for a given terminal voltage is reduced. Therefore, operation within the allowable overfrequency limits of the turbine will not produce

generator overheating as long as operation is within rated KVA and 105% or less of rated voltage.

The turbine underfrequency protection scheme should govern the duration of the abnormal frequency operation of the generator and associated equipment, thus limiting the possibility of turbine damage. This protection scheme should be applied to all steam and combustion turbines, so it would be an advantage to use a scheme that is flexible to protect turbines with different operating frequency limits. The settings should be adjustable, in case turbine designers due to new technological discoveries and improved material applications revise underfrequency operating limits. The protective system should have a level of security consistent with other generator protection relays. In most power systems in North America, the probability of a severe underfrequency event is low; therefore, most of the time the relay system will be called upon to restrain from tripping during normal frequency operation. Station operation information, in the form of an underfrequency condition alarm, is also important. [13]

#### *Turbine Underfrequency Protection Relay Schemes*

The following design criteria are suggested as guidelines in the development of an Underfrequency Protection Scheme:

- Establish trip points and time delays based on the manufacturer's turbine abnormal frequency limits.
- The transmission system load shedding scheme should be the first line of defense against power system off-frequency operation. Coordinate the turbine generator underfrequency tripping relays with the power system automatic load shedding program. Automatic unit trips should occur when the power system load shedding equipment has not been able to restore the grid frequency to normal. In those cases where generators (typically small dispersed generators) must be tripped for their own protection before the automatic load shedding is completed, additional load shedding must be installed to compensate for the generators that trip early. Regional criteria should be in place to make sure this compensating load shedding is provided, when it is necessary.
- If static relays are used, misoperation of a single underfrequency relay should not cause an unnecessary trip of the machine. Failure of a single underfrequency relay to operate during an underfrequency condition should not jeopardize the overall protective scheme
- If digital multi-function generator relays are used, use of two packages for a single generator to provide redundancy of the functions is recommended.
- The turbine underfrequency protection system should be in service whenever the unit is synchronized to the system, or while separated from the system but supplying auxiliary load.

- Provide separate alarms to alert the operator for each of the following:
  - (a) A situation of less than the nominal system frequency band on the electrical system
  - (b) An underfrequency level detector output indicating a possible impending trip of the unit
  - (c) An individual relay failure.

#### *Power Plant Auxiliaries--Underfrequency Considerations*

The ability of the steam supply system to continue operating during an extended period of underfrequency operation is a function of the margin in capacity of the auxiliary motor drives and shaft driven loads. Should frequency fall by 2 Hz or more, power station auxiliaries can trip out, leading to the loss of the station and possibly leading to the collapse of the entire system. The most limiting auxiliary equipment's are generally the boiler feed pumps, circulating water pumps, and condensate pumps, since each percent of speed reduction causes a larger percent of loss of capacity. The critical frequency at which the performance of the pumps will affect the plant output will vary from plant to plant. For 60 Hz systems, tests and experience have shown that plant capability will begin to decrease at 57 Hz [4], and that frequencies in the region of 53 to 55 Hz [3,4,8] are critical for continued plant operation due to the reduction in the output of the pumps.

#### **Abnormal Voltage Protection** [11]

Voltage regulators control the generator excitation levels to ensure the terminal voltage is maintained at a level that is within the rated operating range of the generator. Voltages outside that range could result in damage to the generator or unacceptable power system conditions. Voltages may exceed rated levels during system disturbances, while the generator excitation system is limited by its internal controllers, or is operating in a manual control mode. As noted in System Control earlier, abnormal voltage protection for generators must coordinate with any external control systems regulating the system voltage that would help to restore normal voltage levels at the generator terminals.

#### *High Voltages*

Abnormally high voltages could cause excessive dielectric stress on the generator or unit transformer insulating materials and result in insulation failure. It should be noted that this insulation damage is not the same as equipment damage due to excessively high flux levels as discussed in Overexcitation Protection earlier. At rated frequency, high flux levels always accompany high voltages; so the two phenomena are related. However at higher than rated frequency, proportionally higher than rated voltage will still produce only rated flux level. A common situation where high voltage may exist without high flux levels is during load rejection when the generator will overspeed and voltage may rise while flux remains constant. This is most likely to be

found in the case of hydro-generators, which can be subjected to high overspeed levels with correspondingly high voltages if they are operating in manual excitation control mode.

Overvoltage protection is sometimes provided to protect the generator from excessive dielectric stress. In addition to coordinating with external system voltage control devices, generator overvoltage protection must also coordinate with internal excitation system voltage controllers. Such coordination is not difficult as long as the protection is set to pick up at a higher level than the maximum setting on the generator voltage reference control and the setting of the excitation system volts per Hz controller at a fundamental frequency (if this auxiliary control device is provided). Coordination with exciter controls for temporary excursions above the maximum controlled voltage level is easily achieved with even small time delays on the protection, because the control devices are normally quite fast (exerting control within less than one second).

#### *Low Voltages*

Undervoltage conditions are not usually harmful to generators themselves, so direct undervoltage protection is not normally provided for them. However, overheating due to extended operation at low voltages may damage the auxiliary motors for turbine generator sets. Auxiliary supplies are therefore sometimes monitored by undervoltage relays that may trip the generator off line to protect the motors. Auxiliary undervoltage tripping is usually applied at nuclear generating stations, where the protection of safety related auxiliary equipment is of paramount importance [11]. The undervoltage relays are typically set close to 0.9 PU of normal operating voltage, with time delay to prevent tripping during successful clearing of external faults. However this setting can cause tripping during system disturbances involving sustained undervoltage conditions. This should be recognized when modeling disturbances and when setting system voltage control devices and unit step up transformer taps.

#### *Excitation Systems*

Excitation system protection can sometimes trip a generator unexpectedly during system voltage excursions. This is because the excitation systems rarely operate at their rated limits until the system voltage tries to rise or fall outside its normal operating range (for example, during a system disturbance). Further, during system voltage transients, the excitation control devices may allow short-term operation of the generator and excitation system outside their rated steady state limits. Excitation protection devices must therefore coordinate with the control devices not only in pickup levels, but also in time delays. In both the June 2 and August 10, 1996 WSCC disturbances, hydro-generators at a critical location tripped off line due to unexpected exciter protection

operation and were unable to help maintain reasonable voltage levels at the time they were most needed.

Some exciter protection devices, which may operate unexpectedly during operation at abnormal voltages, are:

- Thyristor overload or short circuit protection
- Any internal unbalance protection devices
- Exciter transformer HV overcurrent and/or overload protection
- Exciter low voltage supply protection or operating limit.

Generator field protection devices, which may or may not be supplied as part of the excitation system, may also cause unexpected trips during voltage excursions. Two such devices are:

- Field overload protection
- Field ground protection

Calculations can and should be done to ensure that protection and control settings coordinate with each other. However, over the life of the generator it is quite possible for protection and control devices settings to drift or to be accidentally altered to negate the theoretical coordination margins. All exciter and field overload and short circuit protection can also be periodically tested by operating the generator at its maximum excitation levels to ensure that controllers operate to keep the generator within safe limits before the protection operates. Such tests may be done not only by bringing the generator slowly up to its steady state limit, but also by bringing it rapidly up to the limit so that coordination for short time operation above the steady state limit can be checked.

Exciter low voltage supply protection or limits may be built into the exciter control system, and may not be capable of adjustment. Such limiting devices will not usually be a problem during system disturbances if the excitation system has been specified to operate during sustained three phase short circuits on the HV terminals of the step up transformer. Under these short circuit conditions, generator terminal voltages drop to the lowest levels possible during system disturbances.

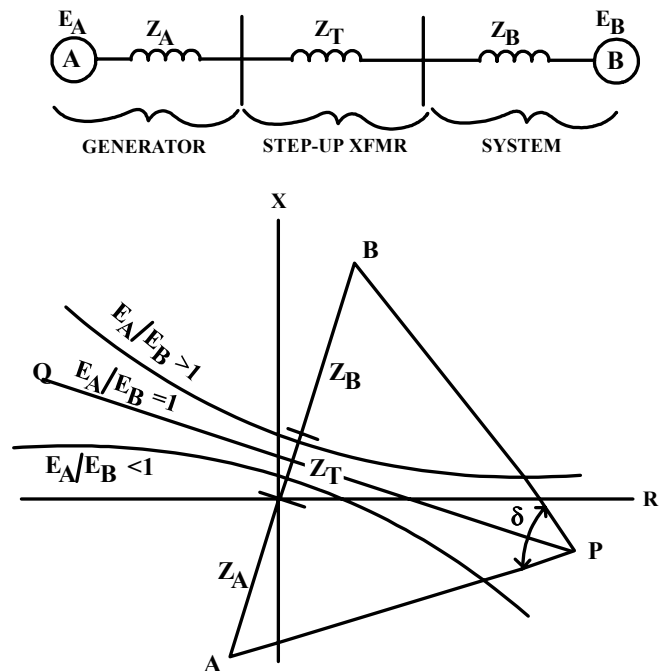
Field ground protection which is sensitive to dc current through the ground insulation resistance may not operate for some faults at a specific location on the field at a given excitation level due to the existence of a possible null point in the bridge sensing the field ground current. However, during system disturbances when the excitation level changes, if the insulation resistance near the null point is near the sensitivity of the ground protection, there may be sufficient dc to cause operation of the protection. Long time delays on the field ground protection may not be sufficient to override sustained operation at a new, different, excitation level in the post disturbance phase. DC field ground protection systems also usually include a test facility that

changes the null point and allows the insulation level at different voltage levels to be checked. Such test facilities should of course be used regularly. Where possible, it is best to use a sensitive ground fault alarm that will indicate resistive ground faults at insulation levels well above the trip level. This alarm will therefore indicate a problem at higher excitation levels that may be present during system disturbances, and will allow the unit to stay on line until it can be conveniently taken off line.

### Out of Step Protection

When a generator loses synchronism, the resulting high peak currents and off-frequency operation can cause winding stresses, high rotor iron currents, pulsating torques and mechanical resonances that are potentially damaging to the machine. To minimize damage the generator should be tripped without delay, preferably on the first slip cycle.

During an out-of step condition the apparent impedance, as viewed from the generator terminals, will vary as a function of system and generator voltages and the angular separation between them. The impedance locus will depend on the excitation system, machine loading and initiating disturbance. Typical out of step impedance loci are shown in Figure 4. [9] With the advent of EHV systems, large conductor-cooled generators and the expansion of transmission systems, the electrical center of the out-of step swing is typically in the step-up transformer or generator.



**Figure 4: Typical Out-of-Step Impedance Loci Using Simplified Graphical Procedures**

While loss of excitation relays or a simple mho relay at the high side terminals of the step-up transformer may provide some protection [9], dedicated relays with either a blinder characteristic supervised by a mho characteristic or with a lens characteristic are usually applied where tripping is desired only for an out-of-step condition and it is required that the generator not be tripped for any stable swing. The characteristics allow discrimination between faults and swings and between stable and out-of-step conditions. Moreover these characteristics allow the tripping signal to be delayed until the angle between the system and generator is reduced to a favorable value, minimizing the stress across the breaker being tripped.

Normally system transient studies should be performed to determine the system impedance swing against time for different scenarios. The relays are set so that they will not trip for any stable swing but will trip if the swing is unstable. The limiting stable swing for the generator is with the generator operating at unity or leading power factor, with the voltage regulator out of service, low system impedance and clearing of the most severe fault at critical switching time. For unstable swings the impedance loci for each generator should be determined with system configurations that give maximum and minimum system impedances and with voltage regulators in and out of service. With different generator loading conditions and system configurations, the transient response of the machines are determined for different fault conditions. Generally systems are required to withstand close in three-phase fault on high side of step up transformer and breaker failure conditions. Even with fast relaying and breaker operating times, this condition may sometimes result in generator loss of synchronism. Out-of-step protection on a generator is required when relatively large generator can go unstable for reasonable system contingencies and the swing goes through the generator/transformer zone.

Many new generating plants are combined cycle, with a combination of gas turbines and a steam turbine at the same location. The latter will normally be lower inertia and will tend to go out of step before the higher inertia units. Out-of-step protection applied on the steam unit can lead to faster recognition of out-of-step conditions and it is possible that, in some cases, tripping of the steam unit quickly will result in the gas turbines staying in synchronization with the system. It has also been suggested that a back-up distance relay, set to trip if the primary breaker does not clear the critical fault, can be used in some conditions to trip the steam turbine and keep the gas turbines on line.

While planning studies can identify what setting to apply to out-of-step relays, it should be recognized that these studies are usually based on limited anticipated scenarios e.g. three phase faults, breaker failure, specific system configurations and loading etc. Severe system disturbances often involve

multiple events with depressed system voltages, switching events and system oscillations. In addition, under abnormal system conditions such as underfrequency, the relay characteristics may vary from ideal. Under these circumstances, application of an out-of-step relay may cause the impedance to enter the relay tripping characteristic for some situations where the machine is not necessarily out of step thus causing nuisance tripping and possibly worsening overall system conditions. Detailed studies of performance under severe multiple contingencies must balance the risk of undesirable tripping against the risk of damage to the machine. The tripping mode recommended (breaker trip, assuming the unit can respond to full load rejection) does allow the machine to be quickly reconnected.

#### **Accidental Energizing Protection** [9] [10]

Accidentally energizing a generator can cause a major system disturbance in addition to causing damage to a generator. Most utilities recognize the need for dedicated protection to quickly detect such an event. The types of schemes being applied today typically include a sensitive overcurrent relay that is enabled by a signal (e.g. frequency, voltage, auxiliary contact, etc.) indicative of the generator being out of service.

Adequate care must be taken in design of the accidental energizing scheme so that the abnormal voltage and/or frequency conditions expected during system disturbance do not incorrectly enable the overcurrent relay and trip the generator.

#### **IV. CONCLUSIONS**

The paper briefly examines causes of power system disturbance and its effect on the system parameters. Normally, Excitation and Turbine Governor Controls of the generators act to stabilize the system. If required, System Controls may also operate. However the power system may experience abnormal operating condition during the time the controls are attempting to stabilize the system.

The paper focuses on effect of the abnormal operating conditions on Generator Protection and ways to minimize it. Lessons learned from some of the major disturbances of the past are presented. The generator protective functions are identified that may be adversely affected.

These functions are summarized in Table 1 along with the Issues involved and suggested Recommendations to minimize their misoperation during the major system disturbances.

TABLE 1  
SUMMARY OF GENERATOR PROTECTION PERFORMANCE DURING MAJOR SYSTEM DISTURBANCES

Function	Issues	Reference Topics	Recommendations
Underfrequency 81U	Coordination with System Control and Machine Capability. Proper operation at low voltages.	WSCC Disturbance System Control	Coordinate settings with System Load Shedding scheme. Do not apply on Hydro Generators. Check operation at low voltage. If electromechanical or static relays used, avoid tripping on one relay misoperation. If digital relays used, consider redundant relays. Severe underfrequency condition may also affect critical auxiliaries.
Overfrequency 81O	Lock out of units on load rejection	WSCC Disturbance	Unit should not be locked out for non fault load rejection
Overexcitation 24	Overvoltage during disturbances/ islanding can cause relay operation if excitation is on manual control. Miscoordination can exist between controls and protection.	WSCC Disturbance Excitation Control	Minimize operation on manual excitation control. Check coordination with excitation controls
Overvoltage 59	Not universally applied. Operation most likely on load rejection and on manual excitation control.	WSCC Disturbance	Any protection should coordinate with excitation controls
Loss of Field 40	Power swings may enter characteristic. Low frequency combined with manual control may cause operation for shaft driven exciters. Characteristics may shift with frequency.	WSCC Disturbance PJM Disturbance Excitation Control	Do system studies to establish swings. Instruct operators to minimize manual excitation control. Check coordination with excitation controls. Relay settings should be coordinated with Exciter MEL and UEL limits to ensure that relay operation allows time for control action.
Out of Step 78	Unit may inadvertently see some swings as out of step conditions.	System Control	Work closely with connected utility on system studies to set relay. Relay should be set to see only true unit out of step conditions. On combined cycles use separate relays on steam and combustion units.
Backup 21	Unit trips because of extended faults or incorrect settings	Tennessee Disturbance System Control	Detailed setting discussion. Limit reach to minimize opportunities for incorrect operations. Improve/implement bus protection and breaker failure protection.
Backup 51V	Unit trips because of extended faults or incorrect settings	WSCC Disturbance Tennessee Disturbance System Control	Detailed setting discussion. Limit reach to minimize opportunities for incorrect operations. Improve/implement bus protection and breaker failure protection.
Ground Backup 51TN	Unit trips because of extended faults or incorrect settings	PECO Disturbance System Backup Protection	Detailed setting discussion. Coordinate with line relays.
Undervoltage 27	Auxiliary systems trip during external faults.	WSCC Disturbance Abnormal Voltage Protection	Possibly add UPS, or trip generator along with undervoltage trip of critical auxiliaries.
Field Ground 64F	May operate at sustained high excitation voltage during disturbances.	System Control Abnormal Voltage Protection	Install a sensitive relay that will alarm on normal operation at a level that could cause tripping at high excitation. Test insulation system regularly.
Exciter Controls and Protection	Coordination with generator protection and system controls. Out of service exciter control is detrimental to system stability.	WSCC Disturbance System Control Loss of Excitation Protection Overexcitation Protection Abnormal Voltage Protection	Keep AVR in service. Ensure coordination of controls, exciter protection settings and relay protection. Periodically test for steady state and dynamic coordination with protection systems

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